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# Reservoir Characterization: Electromagnetic Imaging of CO2 for EOR Processes

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# Electromagnetic Imaging of $CO_2$ for EOR Processes

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## Abstract

Lawrence Livermore National Laboratory is currently involved in a long term study using time-lapse multiple frequency electromagnetic (EM) imaging at a carbon dioxide ($CO_2$) enhanced oil recovery (EOR) site in the San Joaquin Valley, California. The impetus for this proposed research project is to develop the ability to image subsurface $CO_2$ during EOR processes while simultaneously discriminating between background heavy petroleum and water deposits. Using field equipment developed at Lawrence Livermore National Laboratory in prior imaging studies of EOR water and steam injection, this research uses multiple field deployments to acquire subsurface image snapshots of the $CO_2$ injection and displacement. Laboratory research, including electrical and transport properties of fluid and $CO_2$ in saturated materials, uses core samples from drilling, as well as samples of injection and formation fluid provided by industrial partners on-site. Our two-fold approach to combine laboratory and field methods in imaging a pilot $CO_2$ sequestration EOR site using the cross-borehole EM technique is to 1) improve the inversion process in $CO_2$ studies by coupling field results with petrophysical laboratory measurements and 2) focus on new gas interpretation techniques of the field data using multiple frequencies and low noise data processing techniques. This approach is beneficial, as field and laboratory data can provide information on subsurface $CO_2$ detection, $CO_2$ migration tracking, and the resulting displacement of petroleum and water over time. While the electrical properties of the brine from the prior waterflooding are sharply contrasted from the other components, the electrical signatures of the formation fluid (oil) and $CO_2$ are quite similar. We attempt to quantify that difference under multiple conditions and as a function of injection time. We find that the electrical conductivity signature difference increases over time and we should thus expect to discriminate $CO_2$ as a function of time based on the time scales calculated from linear extrapolation of laboratory data.

## Introduction

Lawrence Livermore National Laboratory (LLNL) is currently involved in a long term study using time-lapse multiple frequency electromagnetic (EM) characterization at a $CO_2$ enhanced oil recovery (EOR) site in California operated by Chevron Heavy Oil Division in Lost Hills, California (Figure 1). The petroleum industry's interest and the successful imaging results from this project suggest that this technique be extended to monitor $CO_2$ sequestration at an EOR site also operated by Chevron. The impetus for this study is to develop the ability to image subsurface injected $CO_2$ during EOR processes while simultaneously discriminating between pre-existing petroleum and water deposits. The goals of this study are to combine laboratory and field methods to image a pilot $CO_2$ sequestration EOR site using the cross-borehole EM technique10,11, improve the inversion process in $CO_2$ studies by coupling results with petrophysical laboratory measurements, and focus on new gas interpretation techniques. In this study we primarily focus on how joint field and laboratory results can provide information on subsurface $CO_2$ detection, $CO_2$ migration tracking, and displacement of petroleum and water over time. This study directly addresses national energy issues in two ways: 1) the development of field and laboratory techniques to improve in-situ analysis of oil and gas enhanced recovery operations and, 2) this research provides a tool for in-situ analysis of $CO_2$ sequestration, an international technical issue of growing importance.

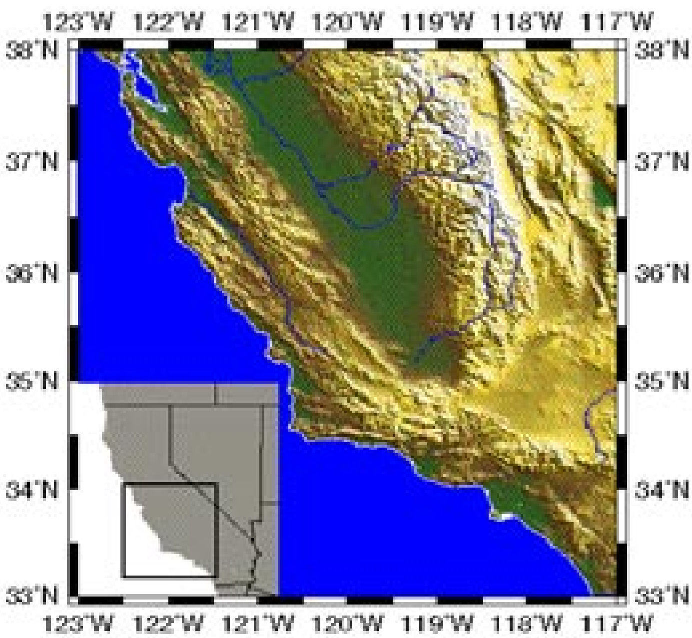


Figure 1. Map showing location of Lost Hills, California oil fields accentuated within the white circle.

Description and Application of Equipment and Processes

Laboratory Approach. We propose to measure the electrical properties of samples from the site at conditions of full liquid saturation with oil and as they are invaded with liquid and gaseous $CO_2$. Measurements are performed at temperatures and pressures appropriate to field conditions in a specially constructed device specifically aimed at these types of measurements. The system (Figure 2) consists of an externally heated fluid pressure vessel capable of confining pressures up to 10 MPa and temperatures up to 300(C. Pressure is controlled by three different pressure systems-one each for confining pressure and upstream and downstream pore pressure control. Electrical measurements are performed using two systems, a Hewlett-Packard HP4282 impedance bridge and a Solartron 1260 impedance analyzer. The HP4284 is used to monitor the sample at specific frequencies during periods of heating, pressure changes, and fluid injection. The impedance analyzer is used to make broadband measurements during (10-3 to 106 Hz) periods when the sample is at stable experimental conditions. The device and measurement methodology has been tested on oil-filled diatomite samples from the Lost Hills that were injected with brine during EOR (Figure2) and the same apparatus is used. Measurements with waterflood showed some unexpected electrical behavior, resistivity increasing during brine injection, that helped interpret the Chevron well-logs and the LLNL crosswell inversions. Measurements for the $CO_2$ flood attempt the same characterization, but in addition, we attempt to predict and discriminate between the oil (formation fluid) and $CO_2$ that have similar electrical properties.

The experimental method, as stated, was originally adapted for brine injection and is now used for the $CO_2$ injection process. A well-characterized water- or oil-saturated sample is placed in the vessel for electrical measurements at the temperature of the formation (~38-45 C) and a variety of confining and pore pressures. Then, liquid $CO_2$ is forced into the sample and the electrical properties monitored as the liquid water is pushed out. This process is easily accomplished at room temperature, as the critical pressure for $CO_2$ at 31(C is 72.8 atm or ~7.3 MPa (CRC, 1983), well within the operating parameters of the device. Changes in the electrical properties are also recorded. Next the pore pressure is lowered so that the liquid $CO_2$ flashes to the gas phase. The electrical properties are again be monitored for a period of time as the sample is held at static conditions to determine if there is a long-term effect. It is important that there is some knowledge of surface conduction mechanisms in the rocks so that any changes in electrical properties because of different surface tensions and wetting behavior can be discerned and understood.
A second type of experiment involves the injection of gaseous $CO_2$. As above, electrical properties are monitored as the sample undergoes invasion of $CO_2$. It is sometimes necessary to pump to relatively high pressures to obtain displacement of water. We will attempt to match reservoir characteristics whenever possible.

Samples undergoing boiling or $CO_2$ invasion may change geochemically. The nature of the geochemical change will be dependent on a number of factors, including rock chemistry, temperature, pressure, water/rock ratios, and fluid chemistry. These changes can affect measured electrical properties, in particular the surface conductance. Geochemistry consultants to this project have to date developed a code that calculates fluid conductivities of mixed fluids at conditions similar to the laboratory apparatus. In this way, we can approximately predict the electrical effect of the geochemical changes.

Field Approach. Electromagnetic techniques are sensitive to rock pore fluids within the subsurface, which makes them the ideal method for addressing the problems of EOR in a heavy oil environment. In EOR applications, it is also important to discern between injection steam and gases, injection fluids, and formation fluids. The high sensitivity of electromagnetic energy to these physical processes, as well as recent advances in computational ability, inversion code resolution, and field instrumentation, make borehole EM techniques an important tool for such subsurface imaging problems.
During $CO_2$ sequestration, the high pressure of the injection forces the $CO_2$ to remain in a liquid state. After delivery to the subsurface formation, however, a volume increase creates a pressure drop can vaporize the $CO_2$ to a gaseous state. It is this possible gaseous state and the more beneficial liquid/supercritical state, which increases miscibility with the water and oil in the subsurface formation, which any imaging attempt must detect.

In this complex scenario, EM imaging must address the multiple-state $CO_2$, the liquid water leftover from secondary recovery, and the original liquid petroleum in the formation. Based on initial forward model calculations, we expect a large contrast between the formation water and the petroleum / $CO_2$ but a small contrast between the $CO_2$of each component. Resolution of this small contrast will be possible with laboratory results and with improved gas interpretation techniques that will be developed based on higher resolution inversion techniques.

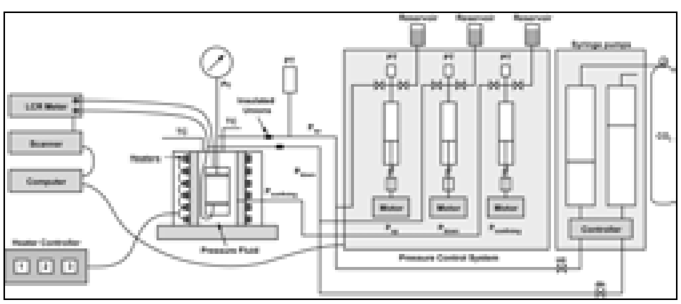


Figure 2 Schematic of the laboratory apparatus used to inject EOR materials through core samples and simultaneously measure

## Presentation of Data and Results

Previously a waterflood site, the proposed $CO_2$ injection location has typically produced a lower petroleum yield than expected during primary and secondary recovery operations. While $CO_2$ injection for EOR provides the advantage of higher production yields and viscosity reduction in heavy oil, it has the disadvantage of increased cost; sequestration of industrially produced $CO_2$ can significantly offset such cost increases. The oil industry is therefore interested in a long-term study into the feasibility of $CO_2$ injection for the purposes of carbon sequestration and subsurface petroleum mobilization with the eventual possibility of running a gas pipeline to injection boreholes if such processes prove economically viable. Initially, two observation boreholes were drilled by Chevron USA, core and fluid samples were made available to LLNL, and because of the highly corrosive $CO_2$ environment, two of the four pre-existing injection boreholes have also been redrilled and electrically characterized. Chevron began injecting $CO_2$ into the mature waterflood site in December 2000 and reached full injection pressure in February 2001. There have been periods of non-injection due to sanding problems. This opportunity to image a carbon sequestration EOR site is unique because it provides a highly controlled and characterized subsurface through a pre-injection deployment to acquire a baseline image and unrestricted access to the observation boreholes. A pre-sequestration baseline data was acquired in August 2000, using source frequencies of 2.0 kHz. and 4.0 kHz. Post injection data was acquired during April, 2001, and October 2001 with the next acquisition planned for April 2002; all post injection surveys acquire complete tomographic data sets at 2.0 kHz., 4.0 kHz., and 6.0 kHz source frequencies.

Results of selected subsurface imaging in the 2-D plane between the boreholes are in Figure 3. The source frequency for these images is 4.0 kHz, although we have similar data for source frequencies 2.0 and 6.0 kHz. The left image is the electrical conductivity structure in the plane between two observation wells in August 2000, while the center image is the same image of the same subsurface section in April, 2001; roughly after three months of $CO_2$ injection. All images were calculated with processing software developed by Lawrence Livermore National Laboratory and Lawrence Berkeley National Laboratory. The finite difference inversion algorithm we have traditionally used, the step to convert the magnetic fields we receive in the field to subsurface electrical conductivity, was developed at Sandia National Laboratory by Greg Newman and David Alumbaugh and is considered a well-characterized and tested code. However, we also have begun using a new finite difference inversion code which relies on an adjoint method to calculate the electrical conductivity6 and uses a more robust forward calculation5 and perfectly matched layer boundary conditions 2 and 9. We also have begun experimenting with parameter estimation to quantitatively characterize the quality of our images 1,3,4,8. These more mathematical subjects are beyond the scope of this paper, but should be stated to ascertain confidence in the images presented.

We can see from Figure 3 that in differencing two data sets (the right hand side plot of Figure 3), one from August 2000, a pre-injection baseline, and April 2001, during injection, most of the changes are occurring in the upper portion of the reservoir (500 m - 525 m). In this region, we can see that $CO_2$ is entering the system because it is the only operation during this time span. Ideally, one would like to understand the percent of oil versus $CO_2$ in this region of change. For this, we look at figure 4 and see the results of a core sample being injected with oil, then $CO_2$, then brine in the laboratory, all the while having the electrical resistivity monitored. It is clear that the longer the $CO_2$ is injected in the system, the lower the resistivity and the larger the difference between the formation fluid (oil). This would suggest that during subsequent images, any change that follows the linear slope of the line in Figure 4, would indicate the presence of $CO_2$. This linear slope with scale factors removed suggests a change of about 12% in the resistivity every six months could indicate the presence of $CO_2$. This is a high rate of change considering the geology of the area does not allow permeabilities to generally surpass 10 mD, so there may be concern for the time scale needed to achieve such phenomena. Figure 5, X-ray imaging of $CO_2$ core samples, however, does suggest that sufficient change can be accomplished with $CO_2$ flooding; there appears to be a complete removal of a surface conductor in a matter of hours.
It is therefore our intention to interpret these images with the ability to discriminate between the oil and $CO_2$, but in a more advanced state, determine crucial factors about the permeability, porosity, or approximate saturation coefficients of each individual component.

Tomographic data sets include 2.0 kHz., 4.0 kHz, and 6.0 kHz. source frequencies and span the entire $CO_2$ injection interval, approximately 460 m - 560 m. Incidentally, the injector is placed approximately between the two observation wells and 5 meters closest to the borehole on the left side. The observation boreholes are separated by approximately 25 meters. Electrical conductivity snapshot images such as Figure 3 are acquired approximately every six months for multiple frequencies that will allow the tracking of $CO_2$, petroleum, and water over increased time.

## Conclusions

Using a crosswell electromagnetic induction system, LLNL has acquired several sets of multiple-frequency time-lapse data sets during the injection of $CO_2$ into a mature waterflood in the central valley of California. This data is processed and inverted to convert the magnetic fields for 2-dimensional sections of electrical conductivity with particular care for the resolution and accuracy of the images.

While the electrical properties of the brine from the prior waterflooding are sharply contrasted from the other components, the electrical signatures of the formation fluid (oil) and $CO_2$ are quite similar. We attempt to quantify that difference under multiple conditions and as a function of injection time. We find that the electrical conductivity signature difference increases over time and we should thus expect to discriminate $CO_2$ as a function of time based on the time scales calculated from linear extrapolation of laboratory data.

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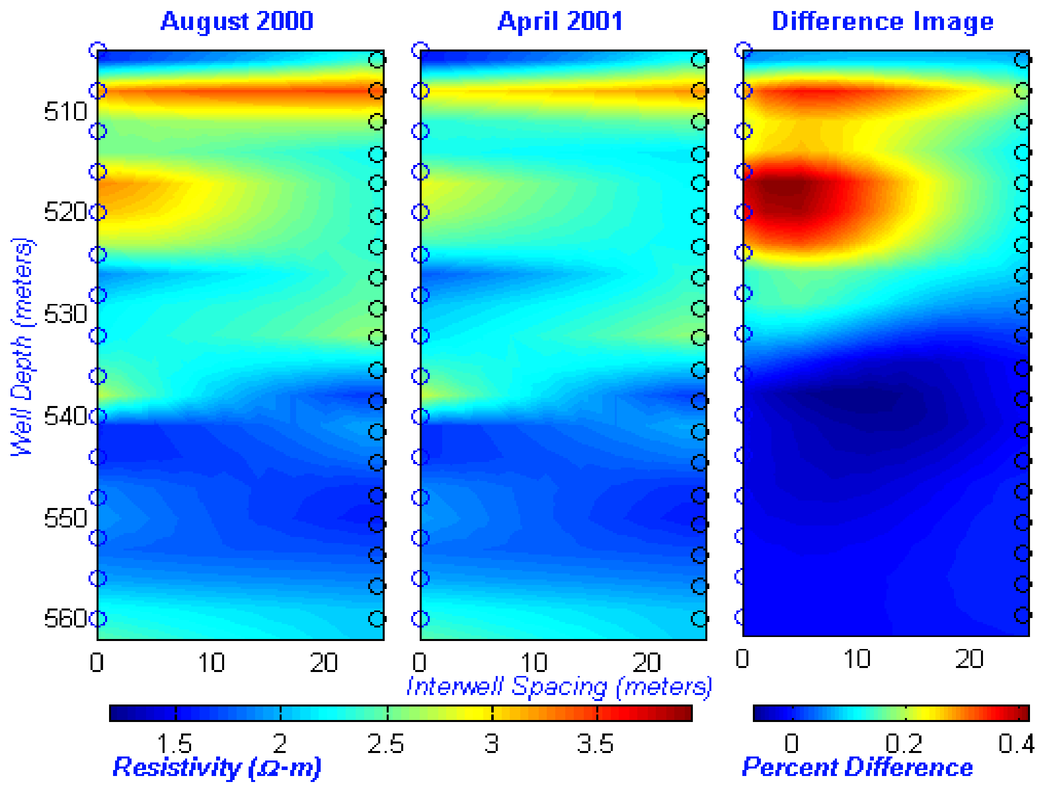


Figure 3 Two-dimensional images of $CO_2$ flooding in the plane between the two observation wells before injection (left) and after 3 months of injection (center). All units in meters and Ohm-meters (resistivity). The circles on the left side of each image represent the well containing the receiver antenna while those circles on the right side of the images contain the transmitting antenna. The difference image (right) is the pre-injection image subtracted from the during-injection image and shows the areas of change quite clearly. A positive percent difference suggests $CO_2$ is entering the area.

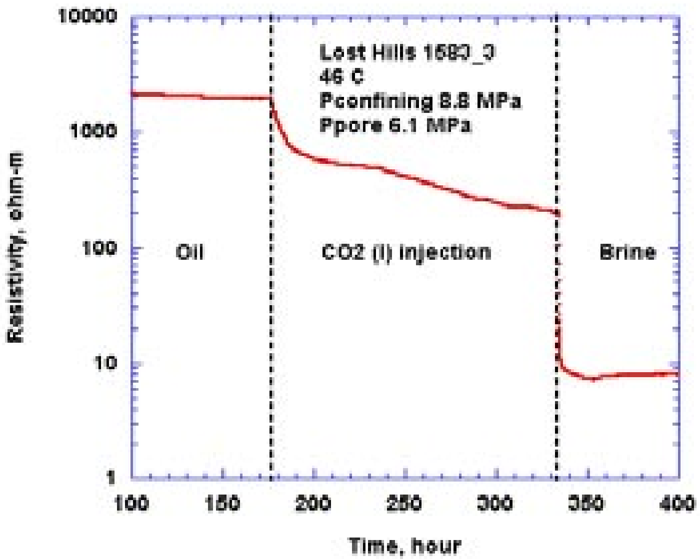


Figure 4 Laboratory core injection of a Lost Hills sample suggests decreasing resistivity during $CO_2$ (liquid) injection process. Linear behavior such as this can help us distinguish the $CO_2$ from formation fluid, heavy oil, by displaying a predicted electrical conductivity change as a function of time. The heavy oil would not exhibit this behavior.

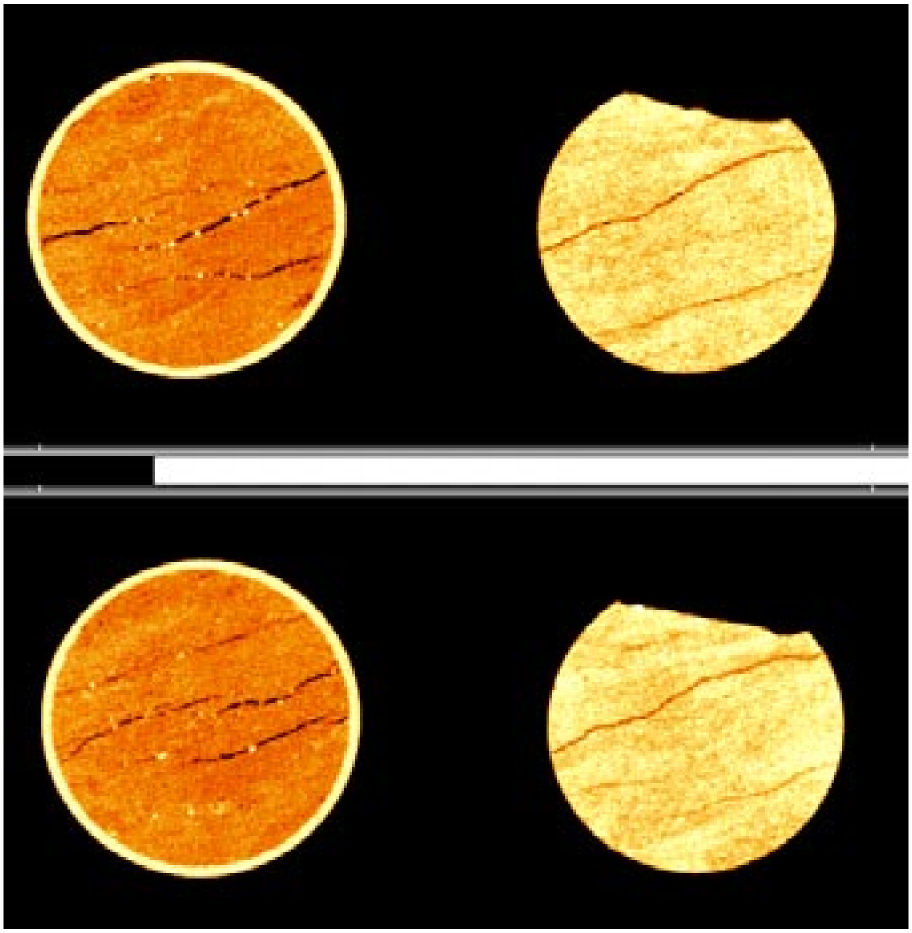

Figure 5 X-ray imaging permits evaluation of fracture flow, fingering, and sweep efficiency. Lower attenuation (red) is indicative of fluids present. This figure displays slices of core samples with the original formation fluid (oil - API index 19) and shown as before (A and B). The samples are then injected with supercritical $CO_2$ and imaged. The white specks in Before A and Before B appear to be washed out by the $CO_2$. From previous laboratory measurements in the area, we know these specks to be a surface conductor, probably pyrite, which affects our EM measurements and must be accounted for. The time between the before and after images is approximately 10 hours. This suggests that $CO_2$ flooding will be an efficient sweep method and we should expect corresponding changes in the field images.